ALJ/KHY/lil/jt2 **PROPOSED DECISION**

Agenda ID #12003 (Rev. 2)
Ratesetting
4/18/2013 Item 9

Decision **PROPOSED DECISION OF ALJ HYMES** (Mailed 3/15/2013)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U-902-M) for Approval of Demand Response Program Augmentations and Associated Funding for the Years 2013 through 2014.	Application 12-12-016 (Filed December 21, 2012)
And Related Matter.	Application 12-12-017

DECISION APPROVING DEMAND RESPONSE PROGRAM REVISIONS FOR 2013 THROUGH 2014

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DECISION PPROVING DEMAND RESPONSE PROGRAM REVISIONS FOR YEARS 2013 THROUGH 2014

1. Summary

This decision approves certain Demand Response program revisions for San Diego Gas & Electric Company and Southern California Edison Company for 2013 and 2014 in order to mitigate impacts of the ongoing outage of the San Onofre Nuclear Generating Station. Given the exigency of this matter, we direct Commission staff to continue to review 2012 Demand Response program data and develop a report on any additional program revisions they recommend as a result of the review and the lessons learned from 2012. The report shall be submitted and served to the parties of record in this proceeding no later than April 30, 2013. Parties and interested stakeholders may file comments to the report no later than 14 days after its service. We will review the report, and associated party comments, and address any recommendations through a subsequent decision. This proceeding remains open to address the staff report.

2. Background

2.1. Demand Response Programs

The Commission broadly defines Demand Response as reductions or shifts in electricity consumption by customers in response to either economic or reliability signals. Economic signals come in the form of electricity prices or financial incentives and reliability signals present themselves as alerts during times when the electricity system is vulnerable to extremely high prices or reliability is compromised. We have generally categorized Demand Response programs according to whether their purpose is to address spikes in market prices in the case of day-ahead and economic Demand Response programs or to relieve threats to system reliability in the case of day-of and reliability Demand Response programs.

California considers cost-effective Demand Response, along with Energy Efficiency programs, to be at the top of the loading order in meeting California's energy needs.[1] Over the past ten-plus years, Demand Response programs provided by Pacific Gas & Electric Company, San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) have played a vital role in providing clean, safe and reliable energy at reasonable rates.

2.2. Mitigating the San Onofre Nuclear Generating Station (SONGS) Outage

SONGS provides substantial capacity to the Southern California region, where the service territories of SDG&E and SCE are located.[2] In January 2012, SONGS Units 2 and 3 were taken out of service, one for a planned outage and one for a malfunction. The outage has continued into 2013 and SONGS Units 2 and 3 are not expected to be brought back into service through 2014. In April of 2012, the Energy Division requested both SDG&E and SCE to propose Demand Response program revisions and improvements to assist in mitigating the effects of the SONGS outage.[3]

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[1] *Energy Action Plan II, Implementation Roadmap for Energy Policies,* developed by the Commission and the CA Energy Commission, September 21, 2005.

[2] SDG&E's entire service territory is in the SONGS-affected area. In SCE's service territory, only the southern portion of Orange County and the region south of Lugo are in the SONGS-affected area.

[3] April 25, 2012 letter from Edward Randolph, Director of Energy Division, to SDG&E and SCE.

SDG&E responded by expanding its Peak Time Rebate (PTR) program eligibility to include small commercial and industrial customers;[4] implementing its Demand Bidding Program that offers incentives to non-residential customers capable of providing at least 5 megawatts (MW) of load reduction during a program event;[5] and deferring the closure of the Critical Peak Pricing-Emergency program until December 31, 2012.[6]

SCE implemented geographic dispatch of its reliability Demand Response programs; created the 10-For-10 program, a new conservation program targeted at Bundled Service commercial, industrial, and agricultural customers;[7] implemented new trigger conditions for all price-responsive Demand Response programs;[8] conducted a residential Summer Discount Plan acquisition campaign; and conducted a marketing campaign in the SONGS-affected area.

Working with the California Independent Systems Operator (CAISO) and the Commission's Energy Division, both SDG&E and SCE created and implemented a daily report to the CAISO and the Commission that provided the amount of available Demand Response in the SONGS-affected areas.

2.3. Procedural Background

On December 21, 2012, SDG&E and SCE each filed an application for approval of revisions to its existing Demand Response programs for 2013 and 2014. The requested revisions are in response to a November 16, 2012 letter from

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4 Approved by the Commission on May 24, 2012, through Resolution E-4502.

5 Approved by the Commission on July 12, 2012, through Resolution E-4511.

6 Approved through a Tier 1 Advice Letter filing, AL-2373-E, effective June 24, 2012.

7 Approved by the Commission on May 29, 2012, through Resolution E-4502.

8 Approved through a Tier 1 Advice Letter filing, AL-2743-E, effective June 1, 2012.

the Commission's Energy Division (Energy Division Letter), which directed SDG&E and SCE to file an application recommending improvements to the Demand Response programs in time for the summer of 2013. The Energy Division letter, attached as Appendix A, explained that the recommended revisions should address at least one of several guiding principles and should rely on the lessons learned from the program revisions during the summer of 2012. In addition, the Energy Division Letter requested specific data and questions to which SDG&E and SCE were required to respond in their applications.

On January 18, 2013, the Alliance for Retail Energy Markets and the Direct Access Customer Coalition filed a joint response to the application supporting the deployment of cost-effective demand response to help ensure reliability. The CAISO also filed a response supporting the applications and providing clarifying comments.

On January 24, 2013, the assigned Administrative Law Judge (ALJ) held a Pre Hearing Conference (PHC) to determine the parties, scope, and schedule, as well as other relevant procedural matters. The assigned Commissioner and ALJ jointly issued a Ruling and Scoping Memo on January 28, 2013 that set the scope and schedule for this proceeding, and directed SDG&E and SCE to serve updated information on January 31, 2013 and responses to omitted data and clarifying questions on February 4, 2013. Intervening parties were given the opportunity to file comments to this proceeding on February 11, 2013; no comments were filed.

On February 11, 2013, SDG&E and SCE each filed a Motion for leave to have their testimony and subsequent supplemental testimony identified and entered into the record. The assigned ALJ issued a Ruling on February 19, 2013 granting the motion to identify and enter exhibits into the record of this proceeding.

On February 21, 2013, the assigned ALJ issued a Ruling requesting SDG&E and SCE to provide additional data to be used to study the lessons learned from the summer of 2012. This proceeding remains open to address any staff recommendations resulting from the 2012 lessons learned.

3. Issues Before the Commission

During the PHC, the assigned ALJ proposed a set of issues to be addressed in this proceeding which the parties discussed. These issues are directly related to the directives of the Energy Division Letter. No party raised any specific safety issues. Thus, the issues to be addressed in this proceeding are as follows:

- How does each of the Demand Response program changes or additions improve the usefulness or availability of Demand Response for 2013 and/or 2014?
- How does each of the program changes or additions comply with the guiding principles provided in the Energy Division Letter?
- How does each of the program changes or additions rely on lessons learned from the Demand Response programs during the summer of 2012?
- Was a complete and correctly-applied cost-effectiveness analysis provided for each requested new funding amount to cover the costs of the program change or addition? Does the analysis meet the required Total Resource Cost (TRC) ratio of 0.9 or higher?
- For each requested fund shift to cover the costs for the program change or addition, did the Applicant thoroughly describe the proposed fund shifting, including any changes to the fund shifting rules approved in D.12-04-045?[9]

[9] D.12-04-045 at Ordering Paragraphs 4, 5, and 6.

4. Overview of Applications

4.1. SDG&E Application

SDG&E requests four Demand Response program revisions. Briefly, they are 1) continue the Demand Bidding Program approved by Resolution E-4511 but modify it to a day-of, 30 minute trigger product; 2) issue a Request For Proposal (RFP) for improving and expanding the use of load control technologies;[10] 3) continue and expand outreach to the SONGS-affected areas by increasing funding for the Community Partners Initiative; and 4) eliminate the PTR program for small commercial customers. SDG&E proposes to fund these revisions through a combination of budget shifts (net $1.76 million) and authorization for additional funding ($1.6 million).

Additionally, SDG&E requests authorization for tariff modifications including the extension of and modification to the Demand Bidding Program, the elimination of its PTR-A tariff and the inclusion of in-home display units as an enabling technology and the experimental electric vehicle rates on its residential PTR program eligibility list.

Although not discussed in the testimony, SDG&E also requests to shift $2 million from its Statewide Marketing, Education and Outreach fund in Application (A.) 12-08-009 to this proceeding.

SDG&E requests that the Commission adopt the revisions in time for the summer of 2013.

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[10] Load control technologies include Air Conditioning cycling and control devices, pool pump cycling and control technologies, and electric water heating cycling technologies.

4.2. SCE Application

SCE requests six Demand Response program revisions to increase Demand Response capacity by up to 58 MW by 2014. Briefly, these revisions are 1) consolidate the Base and Enhanced commercial programs of the Summer Discount Plan into a single year-round program with a new economic-based trigger, shorter anticipated event durations, and less cycling options; 2) increase the Summer Discount Plan enrollment in the SONGS-affected area through a targeted marketing campaign; 3) increase the number of incentives given in the Auto Demand Response Technology program in the SONGS-affected area; 4) increase community-based outreach efforts for Flex Alert in the SONGS-affected area; 5) perform three studies in emerging technologies: pool pump education, integration of pool pumps with Home Area Network (HAN) solutions, and third party programmable communicating thermostats (PCTs); and 6) expand the Save Power Day program in the SONGS-affected area to include a day-of reminder notification, targeted communications, and larger financial incentives.

SCE proposes to fund these revisions by shifting $9.62 million from currently authorized funding for the residential Summer Discount Plan approved in D.11-11-002.

In addition to the program revisions, SCE requests the Commission to approve Advice Letter 2768-E-A in which SCE proposes a plan to improve the cost-effectiveness of its Capacity Bidding Program.

SCE also requests that the Commission adopt the revisions in time for the summer of 2013.

5. Discussion and Analysis

The following subsections provide an overview of the lessons learned from the summer of 2012; a discussion of each program revision requested, how it improves Demand Response and addresses the guiding principles and lessons learned from 2012; a discussion of other requests made by SDG&E and SCE that are related to program revisions; a discussion of the requested cost recovery mechanisms; and, lastly, a discussion of next steps.

5.1. Lessons Learned

The Energy Division Letter specifically directed SDG&E and SCE to "rely on 'lessons learned' about [Demand Response] events from the summer of 2012 (e.g. load impact, evaluations of [Demand Response] programs, customer response) and submit such information in the Applications."[11] The Energy Division Letter also directed SDG&E and SCE to provide outcome data from the summer of 2012 Demand Response programs and to respond to several questions. The data requests and related questions fall under six categories: 1) Demand Response Program Performance, which include load impacts and program operations; 2) CAISO Markets, covering price spikes and market analysis; 3) Customer Experience; 4) Coordination with the CAISO and Utility Operations; 5) Emergency Demand Response Dispatch Order; and 6) Flex Alert Effectiveness. Given the urgency to resolve this proceeding, we reviewed the utility-provided data and responses on two levels for the purposes of this decision: 1) general lessons learned and 2) justifying the requested program revisions. We discuss the general lessons learned here.

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[11] Energy Division Letter at 2.

In reviewing the data regarding Demand Response Performance, we looked at how well the programs performed with respect to load impact results during the summer of 2012. For SCE programs with an event limit, most did not attain the maximum number of events and/or hours except for the Summer Advantage Incentive (SCE's Critical Peak Pricing program). During the summer of 2012, SCE triggered 12 events for the Summer Advantage Incentive, which is within the annual permitted range of 9 to 15 events. But other SCE programs were far below event limits such as the Summer Discount Plan that experienced 23 events and 24 event hours, well below its 180 event hour limit. That being said, most SCE programs experienced event hours within the historical ranges. We conclude that data from the summer of 2012 indicates that SCE's Demand Response Program events and event hours during this time are far less than the allowable maximum events and event hours with the major reasons being trigger conditions, optimal dispatches, and no nomination.

In reviewing the data describing the 2012 summer experience with the CAISO Market, we looked to determine whether and how Demand Response programs impact the CAISO market prices. Because of the mechanics of Demand Response, it is not possible to use Demand Response programs to respond to real time price spikes.[12] Instead, the utilities estimate in advance when price spikes may occur and Demand Response events are scheduled. In theory, Demand Response programs should have some impact on prices given that Demand

[12] Price spikes occur in real time with a 2.5 minute notice. Because of technical limitations, Demand Response programs must be called a day-ahead or the day-of with several hours of notice in advance.

Response events overlapped price spike days[13] with some success. However, the degree to which Demand Response programs mitigated price spikes cannot be quantified and the success with which Demand Response program were able to target price spike days varied. For example, SCE experienced seven days where three or more hours averaged $150/megawatt hour (MWh) or more and, of those seven days, SCE was able to mitigate the price spikes on six days. SDG&E experienced eighteen days where three or more hours averaged $150/MWh, but was only able to mitigate price spikes using Demand Response on four of those days.

In our review of Customer Experience during the summer of 2012, we looked at whether Demand Response program design and operations aligned with customers' expectations and whether the programs experienced customer fatigue. In the case of SCE, customer complaints increased during longer or consecutive days of events. While SCE did not observe any evidence of customer fatigue, SCE monitored the level of fatigue and adjusted triggers as necessary.[14] SCE states that flexibility in program dispatch triggers decreased the occurrence of consecutive days of events, thus decreasing the number of complaints. We conclude that decreasing the length and consecutive days of events may decrease customer fatigue.

SDG&E's residential PTR program experienced significant load reduction from customers who chose to receive notification of events.[15] SDG&E performed

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[13] For the purposes of comparing the two utilities in this review only, we consider a price spike day any day with three or more hours averaging $150/MWh or more.

[14] SCE-01, Appendix C at 14.

[15] SGE-03 at Table 4.

a PTR customer survey which concluded that while small commercial customers had a high awareness level of the program, they were ambivalent about the feasibility of participating in PTR.[16] SDG&E contends that small commercial customers face different challenges than residential customers in responding to program events. We conclude that the PTR program may not be a good fit for commercial customers.

Perhaps due to the expediency of this proceeding, SDG&E and SCE provided insufficient data in the initial applications regarding the 2012 program lessons learned. The Scoping Memo required both utilities to provide updated information on January 31, 2013 and additional clarifying data on February 4, 2013. However, the additional data also lacked the details necessary to ascertain and study the lessons learned in 2012. As previously noted, the assigned ALJ issued a Ruling on February 21, 2013 requesting more in-depth 2012 program data. The data from this proceeding will be used to develop a staff report on lessons learned from the Demand Response programs during the summer of 2012, as further discussed in the "Next Steps" section of this decision.

5.2. Demand Response Program Revisions 2013 and 2014

5.2.1. SDG&E Requested Revisions

SDG&E requested four program revisions: continuing but modifying the Demand Bidding Program to be a day-of 30 minute trigger product; issuing RFPs for new load control technologies; increasing funding for and expanding its Community Partners program to Orange County; and discontinuing its PTR

[16] SGE-02, Attachment 7 at 19-20.

Commercial program. We approve all of these requests as discussed individually below.

5.2.1.1. Demand Bidding Program Revision

As stated above, the Commission approved the initial implementation of SDG&E's Demand Bidding Program for the summer of 2012. SDG&E's current Demand Bidding Program offers incentives to non-residential customers for reducing energy consumption and demand during a specific Demand Response event. SDG&E contends its experience from 2012 shows that with a modification from a day ahead to a day-of 30-minute trigger product, the Demand Bidding Program should prove important in providing reliable demand response. SDG&E requests a budget of approximately $1.76 million to fund the revised program during 2013 and 2014. SDG&E states that this revision fulfills the guiding principle to "provide programs that can provide demand response within 30 minutes."[17]

In our review of whether to approve each requested program revision in this application, we ask whether the revision meets the following criteria. First, does the revision improve the usefulness or availability of a Demand Response program? Second, does the revision meet one or more of the guiding principles of the Energy Division Letter? Third, is the revision based on a lesson learned from the summer of 2012?

We find the Demand Bidding Program proposal to be reasonable. SDG&E's request to revise and continue the Demand Bidding Program meets the requirements of this proceeding in that it improves the usefulness of Demand

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[17] SGE-01 at 6.

Response, meets one of the guiding principles, and is based on a lesson learned from the 2012 season.

The Demand Bidding Program revision requested by SDG&E improves the usefulness of the program by increasing the response time for addressing contingency situations identified by the CAISO and simultaneously meets the guiding principle to provide more demand response within 30 minutes. Program data from 2012 indicates that SDG&E experienced 18 days where wholesale market price spikes occurred. A 30-minute program will allow SDG&E to use the Demand Bidding Program to address real time market conditions better than a Day-Ahead program.

Through the summer of 2012, the Demand Bidding Program's initial season, SDG&E enrolled two customers, only one of which provided a bid.[18] Despite only having one participating customer in this program, SDG&E experienced load impacts of 5.1 MW in August, 5.4 MW in September, and 4.6 MW in October.[19] With the requested revisions to the program, the quantity of MW—albeit small—will provide a consistent and reliable load impact.

In comments, the United States Department of the Navy (Navy),[20] urged the Commission to retain the day-ahead program contending that "reducing the response to 30 minutes will only allow participation from entities with automated demand response systems."[21] The Navy also states that the program as currently structured did not and will not allow its participation. Furthermore, the Navy

[18] SGE-02, Attachment 1(Revised Appendix X) at 7-9.

[19] SGE-01e at 2.

[20] Comments were filed by the Federal Executive Agencies representing the Navy.

[21] Comments of the Federal Executive Agencies, April 3, 2013 at 2.

requested that the Commission direct SDG&E to develop an appropriate program that takes into consideration its operational characteristics.

While we appreciate the desire of the Navy to participate in this program, the scope and record of this proceeding indicates that we should approve the more reliable program. However, because Demand Response programs along with Energy Efficiency programs are at the top of the loading order in California, we welcome increased customer participation in these programs. Thus, we encourage SDG&E to work with the Navy to develop a program that meets the needs of both the Navy and California.

SDG&E's request to continue its Demand Bidding Program with the revision described above is approved. SDG&E is authorized a total budget of $1.76 million for 2013 and 2014.[22]

5.2.1.2. Issue an RFP for New Load Control Technologies

SDG&E requests Commission authorization to issue an RFP seeking "cost-effective proposals for improving and expanding the use of load control technologies which would bring incremental load reduction."[23] SDG&E explains that its Summer Saver program is currently its sole residential demand response program focused on air conditioner direct load control. Stating that the proposed RFP process will "identify new, innovative ways to implement various load control programs" using the most recent efficient devices available,[24] SDG&E contends this request follows the guiding principle to consider new sources of load to be reduced.

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[22] SGE-02 at Attachment 8.

[23] SGE-01 at 7.

[24] *Ibid*.

We find the proposal to issue an RFP for new and innovative load control technologies to be reasonable and we approve its issuance. The RFP proposal meets two of the guiding principles in that it considers a new source of load, i.e. pool pumps, and it could bring to light a new technology that could improve the performance of existing demand response programs. However, we are concerned that nowhere in SDG&E's application or associated testimony do we find a basis for this request from 2012 program results. Furthermore, the Energy Division Letter requested SDG&E to "identify a handful of specific program changes or additions that would improve the usefulness or availability of Demand Response in 2013 and 2014." The proposed RFP timeline would provide program implementation no earlier than the summer of 2014, thus eliminating any load impact for summer 2013.

Despite this delay and the lack of reliance on 2012 data, we find that the RFP could result in several new load control possibilities and could also improve the usefulness of one or more demand response programs. As SDG&E explains, the Summer Saver program is the only residential demand response program based on central air conditioning direct load control. The proposed RFP would look at additional air conditioning cycling and control devices as well as pool pump cycling and control technologies, and electric water heating cycling technologies.

In authorizing the RFP proposal, we also direct SDG&E to work with Energy Division staff to develop an RFP that provides ample opportunities to capture new and innovative load control technologies. SDG&E shall issue the RFP no later than 45 days following the issuance of this decision in order to implement new programs in time for the summer of 2014 and beyond.

5.2.1.3. Continue and Expand Community Partners Initiative

SDG&E requests Commission authorization to continue its Community Partners Initiative in San Diego and to expand the initiative to South Orange County. SDG&E requests a total budget increase of $200,000 for 2013 and 2014 in order to utilize community based organizations to educate customers about Flex Alert and other summer conservation programs. This would continue and expand the efforts of 2012 when SDG&E worked with 36 community-based organizations to provide education to an additional 250,000 hard-to-reach customers.

SDG&E's request to continue and expand its Community Partners Initiative, as discussed above, is reasonable. The Community Partners Initiative would improve the usefulness of Demand Response programs by educating customers on the existence of such programs. Furthermore, by expanding the initiative into South Orange County, SDG&E meets the guiding principle of focusing on the SONGS affected area. 2012 Flex Alert Campaign results show that utilizing community-based organizations increased the number of customers, especially from hard-to-reach communities, benefiting from the knowledge provided.[25]

We approve SDG&E's Community Partners Initiative as proposed and authorize a total budget of $200,000 for 2013 and 2014.

5.2.1.4. Discontinue PTR Small Commercial Program

SDG&E requests authorization to eliminate its PTR program for small commercial customers. SDG&E implemented this program in 2012 as an

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[25] SGE-02, Attachment 1, Revised Appendix X at 27.

expansion of its residential program.[26] SDG&E explains that low load reduction and customer participation and high costs of the Commercial PTR program led to the recommendation for its elimination.[27]

Program results from 2012 show that PTR for small commercial customers did not deliver the load reduction anticipated, providing only a 2 to 4 percent reduction, while PTR for residential customers reduced energy by 6 to 11 percent.[28] Statistics from 2012 also indicate that small commercial customers used the opt-in alert at a much lower rate than residential customers, 0.4 percent compared to 4.3 percent.[29] Program survey results demonstrate that this segment of customer has a general awareness of PTR but event specific awareness is low and, according to SDG&E, these customers have different challenges in responding to event days compared to the residential population.[30]

SDG&E's request to eliminate the PTR program for small commercial customers is reasonable. We recognize that eliminating PTR for small commercial customers does not meet any of the guiding principles of the Energy Division Letter. But continuing this program will not assist SDG&E in combatting the effects of the SONGS outage, especially when statistics reveal the PTR Commercial program to be less than successful.

SDG&E recommends that the remaining $4.98 million in funding for the PTR Commercial program be shifted back to the Capacity Bidding Program. In

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[26] Resolution E-4502 approved the 2012 expansion with a budget of $6.4 million to be shifted from the Capacity Bidding Program to PTR. See SGE-01 at 9-10.

[27] SGE-01 at 8 - 9.

[28] *Id*. at 9.

[29] *Ibid*.

[30] SGE-02, Attachments 5, 6, and 7, general conclusions.

looking at the 2012 program data, the Capacity Bidding Program performed better than the PTR commercial program. For example, the Capacity Bidding Program provided a total of 9-11 MW of load impact in the 2012 summer months. The PTR Commercial Program provided no MW during the 2012 summer months.[31]

We approve the request to eliminate the PTR program for small commercial customers. We address SDG&E's request to shift its funds back to the Capacity Bidding Program in section 5.4.1 of this decision.

5.2.2. SCE Requested Revisions

As discussed previously, SCE requested six program revisions: modifying the Summer Discount Plan trigger; revising the Summer Discount Plan target area; increasing incentives for Auto Demand Response; increasing funding for Flex Alert; performing three emerging markets studies; and modifying the Save Power Day Residential program. We deny the request to increase incentives for and to add a day-of notification to the Save Power Day Residential program. However, as discussed below, we approve requests for the three emerging technologies studies and revisions to the Summer Discount Plan, Auto Demand Response program, Flex Alert and the Save Power Day education and outreach, for an additional 58 MW of load impact.

5.2.2.1. Summer Discount Plan Trigger Modification

SCE's Summer Discount Plan is a day-of air conditioning cycling program offered to both residential and commercial customers. Enrolled customers have a SCE-installed remote-controlled device on their air conditioner. During

[31] SGE-01e at 2.

curtailment events, a participating customer's air conditioning compressors are remotely cycled off and on, as necessary, to control the unit's load. In return, the customer receives an incentive in the form of a monthly credit from June to October. In 2012, SCE implemented modifications to the Residential program changing the program from an emergency-based summer only to an economic-based year-round program. Because of the success of the program in 2012, SCE is proposing similar modifications to the Commercial program at a cost of $693,000 for an additional 2 MW of load impact.

SCE proposes to add a new economic-based trigger to the Summer Discount Plan Commercial program, allowing events to be called when wholesale market prices are high. In addition, SCE plans to expand the Commercial program to be year-round to address situations that can occur throughout the year. Furthermore, SCE intends to consolidate the current Base and Enhanced options of the Commercial program into one program that offers customers three choices of cycling options from 30 percent to 100 percent, where the 30 percent option reduces load during an event and the 100 percent option deactivates the compressor during an event.

SCE proposes to offer higher incentives for the newly combined program as compared to the current Enhanced programs for each cycling option.[32] For example, SCE proposes $12.69/ton/month for the 100 percent cycling option as compared to $12.00/ton/month under the current Enhanced program.

We find the proposed modifications to the Summer Discount Plan Commercial program to be reasonable. The modifications improve the

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[32] SCE's current Enhanced program incentives are approximately twice as much as the Base program incentives.

availability of the Demand Response program, thus meeting at least one of the guiding principles. By modifying this program to an economic-based program, SCE increases its ability to rely on this program more often. In 2012, the emergency-only program was triggered one time but provided 3.1 MW.[33] Thus, increased reliance resulting from the proposed modification should increase load impacts. Additional 2012 data shows that customers are motivated by maximum bill savings, but prefer shorter curtailment events, even if they happen more often. The proposed revisions provide customers the options for maximum bill savings while increasing the opportunity for improved customer participation and load impacts.

We approve the proposed modifications to the Commercial Summer Discount Plan program and authorize a budget of $693,000 for the additional 2 MW of load impact.

5.2.2.2. Increase Enrollment of Summer Discount Plan in Target Area

SCE proposes to increase the enrollment of the Summer Discount Plan Residential and Commercial programs, but target the enrollment to customers in the SONGS affected area. During 2013 and 2014, SCE plans to target enrollment in 61 cities and approximately 470,000 residential customers, and provide Summer Discount enrollment information to its commercial customers in the South of Lugo area at a total cost of $1.9 million.

In 2012, SCE increased Summer Discount Plan marketing to south Orange County customers adding nearly 4000 enrollments leading to an

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[33] SCE-01a, Appendix A, Table 6 at A-5.

additional 7.5 MW of load impact.[34] Simultaneously, a limited campaign was conducted in the South of Lugo area achieving 3,400 enrollments and 7MW of load impact.[35]

We find the proposal to increase marketing of the Summer Discount Plan in the South of Lugo area to be reasonable. The proposal improves the usefulness of Demand Response by increasing the potential load impacts of the residential Summer Discount Plan by 40 MW. Pinpointing additional marketing of the program meets the guiding principle to target the SONGS affected area. Statistics from 2012 show that increased marketing to specific areas result in increased load impacts.

We approve the targeted marketing for SCE's Summer Discount Plan program and authorize a budget of $1.9 million for the additional 40 MW.

5.2.2.3. Increased Incentives for Auto Demand Response

Auto Demand Response allows customers to reduce their electricity usage through the use of automated enabling technology. These technologies provide customers flexibility without manual intervention. SCE requests approval for an additional $5 million in funding for the Auto Demand Response technology incentives, proposing that the additional incentives be earmarked for customers in the SONGS affected area. SCE explains that current funding levels have left the program 100 percent subscribed; thus, Auto Demand Response cannot

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[34] SCE-01 at 20.

[35] *Ibid*.

provide any additional MW in the target area beyond its current 2012 level.[36] SCE anticipates an additional 16 MW of Demand Response from this effort.[37]

The Auto Demand Response proposal targets customers in the SONGS affected area, thus meeting one of the guiding principles. SCE provides no data from 2012 to support its theory that increasing funding for incentives would increase the load impact. However, in the most recent Demand Response program approval, D.12-04-045, the Commission approved an Auto Demand Response incentives budget of $35.6 million. In that decision, the Commission noted that "limited data" suggests that Auto Demand Response customers have a higher participation rate in Demand Response programs. PG&E's testimony in that proceeding also suggested that these customers provide better load shed.[38] Given the high probability that customers receiving these incentives will provide the additional 16 MW, we find the proposal reasonable.

We approve the Auto Demand Response proposal and authorize a budget of $5 million, $4.2 million of which shall directly go to incentives. We remind SCE of the other Auto Demand Response requirements of D.12-04-045: to implement the 60-40 incentive split for 2013, require a three-year enrollment of customers into a Demand Response program, and to fund Auto Demand Response technologies that interoperate using generally accepted industry open standards or protocols.[39]

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[36] SCE-02 at 18 and SCE-01 at 21.

[37] SCE-01 at 22.

[38] D.12-04-045 at 138.

[39] *Id*. at 142-144.

5.2.2.4. Increased Funding for Flex Alert

Flex Alert is a statewide marketing program that encourages residential customers to reduce their demand when the CAISO issues an Alert or Warning Notice. Funding for the Flex Alert campaign expired at the end of 2012. New funding has been proposed through a statewide marketing education and outreach application with a final decision anticipated simultaneously to this decision.[40] Given the SONGS outage and the urgency of the matter, SCE requests 2013 funding in the amount of $175,000 for community-based grassroots outreach efforts on the Flex Alert program targeted to the SONGS affected area.[41]

SCE explains that, in 2012, SCE created a marketing and outreach campaign consisting of Flex Alert posters and Summer Readiness brochures in various languages and distributed them to approximately 200 community and faith based organizations. The 2012 campaign targeted customers in the SONGS affected area, educating them on conservation steps to take during hot weather. SCE claims that the action built awareness within underserved communities. SCE states that a study performed in August 2012 indicated that more than half of residential customers and one-third of small business customers made "a lot of effort during peak hours to reduce their energy consumption."[42] The study also showed that 83 percent of residential customers and 78 percent of small business

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[40] See Application 12-08-009.

[41] The funding request in this application is focused on community-based outreach and eduction efforts and should not be confused with the funding being addressed in A.12-08-009 which focuses on paid advertising and administration costs.

[42] SCE-01 at 29.

customers in Orange County read or looked at SCE's targeted summer communications.[43]

We find the proposal to target education and outreach to the SONGS affected area to be reasonable. The proposed additional funding for targeted Flex Alert outreach should improve the usefulness of Demand Response by educating customers on conservation efforts. Targeting the efforts to the SONGS affected area meets one of the guiding principles required of these program revisions. Furthermore, studies from 2012 show that such targeted efforts are not only successful in educating customers, but also may lead to increased efforts to conserve energy during peak hours.

We approve SCE's marketing and outreach proposal and authorize a budget of $175,000 to fund education and outreach on the Flex Alert program.

5.2.2.5. Emerging Technologies Studies

SCE requests authority to perform three studies designed to identify new opportunities for Demand Response through the use of pool pumps and thermostats:

- *Pool pump education measure study*: the education measure study will leverage existing energy efficiency programs to offer a pool pump education measure. SCE anticipates that, if successful, the education measure could reduce peak usage of the 5000 pilot installations by 3.2 MW.[44] SCE requests $500,000 for the two-year pool pump education measure study.
- *HAN controlled pool pump*: the HAN controlled pool pump study will evaluate the performance of HAN devices using SCE's SmartConnect

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[43] *Ibid*.

[44] Assumes 50 percent of the participating devices would have been operational during peak hours and each pump has an average demand of 1.3kW. (See SCE-02 at 2, Lines 27 and 3, Lines 1-2.)

platform for curtailment and communication. SCE anticipates that 500 pilot participants will receive qualifying equipment, installation services, and an up-front incentive payment at a cost of $350,000 during 2013. SCE estimates a maximum load impact of 0.68 MW.[45]

- *Third-party PCT*: the PCT study will leverage an existing population of installed residential PCTs in the SONGS affected area to enable direct control of cooling systems. SCE plans to use broadband Open Auto Demand Response to study reliable event communication for dispatch of customer devices. SCE anticipates enrolling 3,000 customers from the SONGS affected area with an estimated cost of $125,000 for the two-year study.[46] SCE expects that leveraging existing PCTs can deliver up to 4.7 MW peak shaving potential.[47]

We find SCE's three proposed emerging technology studies to be reasonable. The studies, if successful, will improve the usefulness of Demand Response programs by increasing load impacts. All three of these studies focus on customers in the SONGS affected area and target new sources of load (pool pumps and Air Conditioning via PCTs) that can be reduced, thus meeting two of the guiding principles required for this application. All three studies also evolve from lessons learned in 2012. The two pool pump studies take into account 2012 survey results which indicate that less than five percent of customers surveyed turn off pool pumps.[48] In the Summer Discount Plan customer satisfaction surveys, 65 percent of respondents expressed a desire for shorter and more frequent events.[49] For the PCT study, it is possible that this unique and rarely-

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[45] Based on 500 participants and an average demand of 1.36kW per pump. (See SCE-02 at 5, Lines 24-25.)

[46] SCE-01 at 26.

[47] *Id.* at 27.

[48] SCE-02, Appendix A at 9.

[49] SCE-02, Appendix D at 21.

used approach to demand response—using Open Auto Demand Response with Residential Customers—will result in shorter event durations.

We approve all three studies and authorize total budgets of $500,000 for the education measure, $350,000 for the HAN pool pump study, and $125,000 for the PCT study. SCE shall comply with all prior Emerging Technology project reporting requirements as discussed and directed in D.12-04-045.[50]

5.2.2.6. Save Power Day Program Modifications

Save Power Day is a residential Demand Response program which gives bundled service customers a bill credit for reducing energy use between 2pm and 6pm on event days. Customers with Smart Meters are automatically enrolled in this program. Currently, customers may elect to receive a day-ahead notification of an event by email, telephone or text message. Nearly four million residential customers are enrolled in this program with approximately 824,000 receiving advance notifications. SCE requests the Commission authorization to implement a day-of reminder notification for all customers enrolled in the event notification program at a cost of $347,000 annually for 2013-2014. SCE also requests to implement a trial that would increase the incentives for the Save Power Day program by $0.50/kWh for customers in SONGS affected areas. The costs to implement the trial are estimated at approximately $150,000. In addition, SCE requests to target the SONGS affected area with additional education and outreach efforts. SCE will fund the additional education efforts with Summer Power Day funds previously approved in D.12-04-045.[51]

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[50] D.12-04-045 at 145-146 and at Ordering Paragraph 59.

[51] SCE-01 at 28.

By targeting the SONGS affected area, all three proposals meet one of the guiding principles. However, in looking at survey data from 2012, only the targeted education and marketing program make sense. Survey results indicate that the targeted marketing and notifications were successful. Over 90 percent of all respondents of the survey found the informational materials they received to be either somewhat useful or very useful.[52] Most customers (66 percent) who received notification were satisfied with the time between notification and the actual event.[53] When asked a preference of notification time, only 19 percent wanted to be notified four to twelve hours before an event, while 37 percent wanted to be notified between twelve and 24 hours before an event.[54] Furthermore, 34 percent wanted to be notified more than 24 hours before an event.[55] Clearly, a day-of notification is not necessary. We find the request to implement a "day-of" reminder to be unnecessary and deny it. However, we find the targeted marketing to be successful and approve SCE's request to continue targeted marketing for the Save Power Day program.

We are concerned about the implications of the proposal to increase the per kWh amount for Save Power Day incentives in the targeted area. While it follows one of the guiding principles, there is no data from 2012 that would justify such an increase. Encumbering our analysis is the fact that SCE's current Save Power Day program provides the same incentive to the entire defaulted population. Thus, we do not have data on the effect of increased incentive levels.

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52 SCE-02, Appendix A at 12.

53 SCE-02, Appendix A at 15.

54 *Id*. at 16.

55 *Ibid*.

It is reasonable to deduce that an increased incentive would provide more load reduction, but the inability to extract specific data creates a barrier to reach such a deduction.

In addition to the data barrier, we are confronted with two other concerns. First, SCE's 2012 Settlement and its Ex Post results indicate that customers received bill credits for MW based on settlement data. Specifically, the number of MW in the settlement data is greater than the actual MW delivered. While this problem may be attributed to a baseline methodology issue, SCE's proposal to increase incentives for customers in the SONGS-affected area could exacerbate the problem. Second, SCE currently offers the same level of incentive for adopting enabling technology. Approving SCE's proposed PTR incentive may effectively reduce customers' incentive to install enabling technology.

Compounding these concerns is 2012 program data indicating that the advance notification option produced a higher load impact than other options. Specifically, customers who proactively enrolled in the advance notification option provided the most load reduction with an average event hour load impact of 0.097 kW. In comparison, defaulted customers[56] provided a lower than average load impact and customers without direct notification produced no significant load reduction.[57]

Given these concerns and statistics, we find only disadvantages to providing increased incentives to customers in the SONGS affected area and, therefore, we deny SCE's request.

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[56] Customers with Smart Meters are automatically defaulted to receive advance notifications of Save Power Day events.

[57] SCE-01a at 4.

5.3. Miscellaneous Requests

5.3.1. SDG&E Tariff Modifications

As we previously described, SDG&E requests authorization for tariff modifications related to the Demand Bidding Program, the PTR program, experimental electric vehicle rates, and in-home display units. We have already discussed and approved the revisions to the Demand Bidding Program and the elimination of the PTR commercial product; thus we approve the related tariff changes requested by SDG&E. In comments, SDG&E requested two other non-substantive tariff changes: 1) the deletion of "2012" in the heading of the tariff; and 2) the removal of a reference to the dates May 1st to October 31st.[58] Because the Commission previously authorized the program to be year-round, it is reasonable to allow these two additional changes as they are typographical and non-substantive. We discuss the other requests individually below.

SDG&E requests approval of three additional experimental Electric Vehicle rates (EPEV-L, EPEC-M, and EPEV-H) to be included on the PTR tariff. SDG&E explains that the exclusion of these three rates as eligible for PTR was scheduled to expire on December 31, 2012. The current tariff for PTR states that Electric vehicle accounts billed on experimental rates EPEV–X, EPEV-Y, and EPEV-Z will not be eligible for PTR until the completion of the electric vehicle study on December 31, 2012.[59]

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[58] SDG&E Opening Comments, April 4, 2013 at 3.

[59] SDG&E explains in its Electric Vehicle Report that EPEV-X through EPEV-Z were replaced with EPEV-L, EPV-M and EPEV-H because the new codes clarified which rates have stronger price ratios or signals. For example, EPEV-L has a low price ratio, EPEV-H has a high price ratio and EPEV-M has a price ratio between the two. See SGE-01a, Attachment 4 at 8.

Adding the three Electric Vehicle rates to SDG&E's PTR tariff meets the guiding principles of increasing Demand Response programs in the SONGS affected area and providing a new source of load. However, the requested tariff modification is in opposition to 2012 program data.

First, the Electric Vehicle Pilot Report referenced by SDG&E indicates that electric vehicle customers have a preference for off-peak charging.[60] Current Electric Vehicle rates already provide an incentive consistent with this preference. Furthermore, eighty percent of all electric vehicle charging occurs during the super off peak period.[61] Program data from 2012 reveals no need for an additional incentive nor does it appear that the PTR incentive would provide significant peak load reduction.

Second, both SDG&E's 2012 Settlement results and 2012 Ex Post results for residential PTR indicate that customers receive incentives for MW above what is actually delivered.[62] While this may be a problem due to the baseline methodology, overlaying a second incentive could exacerbate the problem. Moreover, SDG&E offers no evidence that providing electric vehicle customers a PTR incentive in addition to the current incentive would result in additional load reduction.

For these reasons, we deny the request by SDG&E to add the three additional electric vehicle rates to the PTR tariff.

SDG&E requests authorization to revise its PTR tariff to include In Home Display units as an enabling technology under special condition 8. SDG&E

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[60] SGE-02, Attachment 4 at 1.

[61] *Id* at 40.

[62] SGE-01b at Table 1.

explains that In Home Display unites were addressed in approved Advice Letter 2351-E, but were not included in the actual list of technologies. This revision would continue the practice, under the PTR tariff, of providing incentives to customers using these devices. The practice expired at the end of 2012.

The continuation of providing this incentive to customers in San Diego meets the guiding principle of targeting customers in the SONGS affected area. Results from 2012 PTR program performance indicate that, during PTR events, 650 customers with an In Home Display unit saved an average of five to eight percent of energy usage compared to customers without these devices who saved zero to two percent.[63] We find the request to continue the inclusion of In Home Display units to be reasonable and approve the PTR tariff revision.

5.3.2. SDG&E's Request to Shift ME&O Funds

Although not discussed anywhere in its testimony except in a Program Implementation Plan (Attachment B to its testimony), SDG&E requests the Commission to shift $2 million that it has requested in the Statewide ME&O proceeding (A.12-08-009) to this proceeding in order to cover costs for the Flex Alert Program.

Because this request is neither based on a guiding principle or on a lesson learned from 2012, and because we specifically ordered SDG&E to request this funding in the Statewide ME&O proceeding, we deny this request.

5.3.3. SCE's Advice Letter 2768-E-A

In D.12-04-045, the Commission found that SCE's Capacity Bidding Program failed to meet the cost-effectiveness standards set in that decision. The

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[63] SGE-02 at 5.

Commission directed SCE to increase the outcome of the TRC to 0.75 for 2013 and to 0.9 for 2014. SCE filed Advice Letter 2768-E on August 28, 2012 and on October 25, 2012 filed Supplemental Advice Letter 2768-E-A making additional program changes but not modifying the TRC cost benefit ratios. The two filings made several changes to the program, including modifying monthly program availability hours from 24 to 30 and revising tariff language to allow for geographic dispatch. Energy Division rejected the Advice Letter based on the cost-effectiveness TRC ratios of 0.88 for the day-of option and 0.86 for the day-ahead option.[64]

SCE requests the Commission to approve Advice Letter 2768-E-A, stating that the Capacity Bidding Program supports the Aggregator Managed Portfolio (AMP) program contracts by allowing the AMP contractors to better manage their MW commitment to SCE. SCE contends that the proposed program revisions improve the TRC cost-benefit ratios to 0.88 for the day-of option and 0.86 for the day-ahead option for years 2013-2014.[65] While acknowledging these ratios do not meet the 2014 requirements as set forth by D.12-04-045, SCE explains "the diminishing returns and operational challenges of further program cost reductions" make this proposal "its best and most reasonable effort in achieving the Commission's order without terminating the program.[66] SCE suggests that proposed future changes to the cost-effectiveness protocols would render its Capacity Bidding Program cost-effective.[67]

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64 Disposition of Advice Letter 2768-E-A mailed on December 20, 2012.

65 SCE-01, Appendix D (Advice Letter 2768-E), Attachment A at 8, Table 6.

66 *Id*. (Advice Letter 2768-E) at 3.

67 SCE-01 at 37.

We find the adopted revisions to the Capacity Bidding Program result in TRC cost-benefit ratios of at least 0.75 for year 2013, thus meeting the requirements of D.12-04-045 for 2013.[68] We approve the Capacity Bidding Program, as revised, for year 2013. The Commission plans to open a new rulemaking to review the cost-effectiveness protocols. Following any changes to the protocols as a result of that proceeding, SCE shall file a new Advice Letter requesting approval of the Capacity Bidding Program for 2014 and including the revised cost-effectiveness analysis.

5.4. Cost Recovery Issues

5.4.1. SDG&E Cost Recovery Requests

SDG&E requests approval of $1.63 million in additional funds to continue the Capacity Bidding Program and the Community Partners Initiative. Additionally, SDG&E requests authorization to shift the unspent PTR budget funds of $4.98 million back to the Capacity Bidding Program budget. Lastly, SDG&E also requests authorization to shift the remaining $1.76 million in 2012 Demand Bidding Program funds to the program fund in 2013 and 2014.

SDG&E explains that when the Commission approved the PTR Commercial program for 2012, it also required the fund shifting of $6.4 million from the Capacity Bidding Program to the new PTR program.[69] With the elimination of the PTR Commercial program, SDG&E requests the Commission to shift the remaining $4.98 million back to the Capacity Bidding Program. Additionally, SDG&E requests the Commission to authorize $1.43 million to

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[68] SCE provided a cost and benefit analysis in SCE-01, Appendix E.

[69] Resolution E-4502 adopted by the Commission on May 24, 2012, approved Advice Letter 2351-E requesting approval of the new PTR program and related fund shift.

restore the authorized Capacity Bidding Program back to the level initially authorized in D.12-04-045.

This request is consistent with the current fund shifting rules and does not require changes or exemptions to those rules. Because the Commission authorized the PTR Commercial program as part of the 2012 reliability planning to address the SONGS outage, effectively reducing SDG&E's 2012-2014 Capacity Bidding Program budget, we find the request for fund shifting and additional budget authorization to be reasonable. Because SDG&E is requesting the funds for an otherwise unchanged Capacity Bidding Program, there is no need for SDG&E to produce a new cost-effectiveness analysis. SDG&E is authorized to shift $4.98 million from the PTR Commercial program fund to the Capacity Bidding Program fund for 2013-2014. SDG&E is further authorized an additional $1.4 million for the 2013-2014 Capacity Bidding Program to recover costs shifted to the PTR Commercial program in 2012.

SDG&E has requested an additional amount of $200,000 to fund the Community Partners Initiative that we approved previously in this decision. Because funding for any marketing efforts is spread across all programs and the other programs are remaining unchanged in the foreseeable future, we do not require SDG&E to produce a new cost-effectiveness analysis. We authorize the additional $200,000 in funds to cover the costs of the Community Partners Initiative.

We approved the continuation of the Demand Bidding Program previously in this decision. While not required for programs funded by a shifting in funds, SDG&E provided a new cost-effectiveness analysis that complies with the cost-effectiveness protocols and the requirements of D.12-04-045 and this proceeding. We find the request to shift funds from the 2012 Demand Bidding Program to the

2013-2014 program to be reasonable. The request to shift funds is consistent with the current fund shifting rules and does not require changes or exemptions to those rules, SDG&E is authorized to shift $1.76 million from the 2012 Demand Bidding Program budget to the 2013-2014 Demand Bidding Program budget. We authorize a total budget of $3.4 million for SDG&E's 2013-2014 Demand Response program proposals adopted in this proceeding.

The authorized budgets for SDG&E's 2013-2014 approved Demand Response program revisions are presented in Table 1.

Table 1

San Diego Gas and Electric Company
Authorized Budgets for
2013 and 2014 Demand Response Program Changes

Funding Categories	Fund Shifting	New Funds	Total Authorized Budgets
Category 1 - Reliability Programs: Demand Bidding Program	$1,755,808	-	$1,755,808
Category 2 - Price Responsive Programs: Capacity Bidding Program Peak Time Rebate A	$4,983,649 ($4,983,649)	$1,431,108 -	$6,414,757
Category 7 - Marketing, Education and Outreach: Customer Education and Outreach	-	$200,000	$200,000
TOTAL	**$1,755,808**	**$1,631,108**	**$3,386,916**

5.4.2. SCE Cost Recovery Requests

SCE requests to recover all costs in this application through funding shifting. SCE requests to shift $9.6 million authorized in D.11-11-002 for its Summer Discount Plan Transition program to its 2012-2014 Demand Response

Budget Category 2. SCE also requests to shift portions of the $9.6 million within Category 2 to Categories 4 and 7.

The current fund shifting rules prohibit the shifting of funds between categories. SCE's request, if approved, requires either a change in rules or an exemption to the rules. We find nothing in the record to lead us to change the fund shifting rules. However, given that the funds being shifted to other categories were authorized outside of the 2012-2014 Demand Response Applications and the revisions being requested are to mitigate 2013 and 2014 potential reliability issues resulting from the SONGS outage, we find it reasonable to permit this one-time exemption to allow the funds to be shifted between categories. SCE is authorized a budget of $8.8 million for its 2013-2014 Demand Response program revisions and shall shift this amount from the Summer Discount Plan Transition program to the 2012-2014 Demand Response Budget – Category 2 and then shift $5.975 million to Category 4 and $2.106 million to Category 7. We reiterate that this is a one-time exemption allowed solely because of the reliability concerns due to the SONGS outage.

The authorized budgets for SCE's 2013-2014 approved Demand Response program revisions are presented in Table 2.

Table 2

Southern California Company
Authorized Budgets for 2013 and 2014 Demand Response Program Changes

Funding Categories	**SCE Proposed Budgets & Fund Shifting for 2013-2014**[70]	**Authorized Budgets & Fund Shifting for 2013-2014**
Category 2 - Price Responsive Programs		
Summer Discount Plan – Commercial Transition	$693,000	$693,000
Save Power Day Initiatives	$842,930	$ 0
Category 2 Total	**$1,535,930**	**$693,000**
Category 4 - Emerging & Enabling Technologies		
Auto Demand Response	$5,000,000	$5,000,000
Emerging Markets & Technologies	$975,000	$975,000
Category 4 Total	**$5,975,000**	**$5,975,000**
Category 7 - Marketing, Education and Outreach:		
Statewide Marketing		
Statewide Emergency Alert Marketing	**$175,000**	**$175,000**
Local Marketing		
Summer Discount Plan – Residential	$1,826,000	$1,826,000
Summer Discount Plan – Commercial	$105,000	$105,000
Subtotal Local Marketing	**$1,931,000**	**$1,931,000**
Category 7 Total	**$2,106,000**	**$2,106,000**
TOTAL	**$9,616,930**	**$8,774,000**

5.5. Next Steps

SDG&E and SCE provided the Commission with data and operational results of the 2012 Demand Response programs. The necessity to move this

[70] SCE-01b, Table VI-8.

proceeding in an expedient fashion did not provide adequate time for staff to fully review and analyze this data. Staff is directed to continue its analysis and serve a report to the parties of this proceeding by April 30, 2013. The staff report should describe the lessons learned from 2012 Demand Response programs and recommend any additional Demand Response program or operational revisions, including continuing, adding, or eliminating Demand Response programs. Parties to the proceeding and other stakeholders may file and serve comments to the staff report no later than 14 days after the filing of the report. A subsequent Commission decision may be issued to address recommendations resulting from the staff report. This proceeding remains open to address the staff report.

6. Comments on Proposed Decision

The proposed decision of ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on April 4, 2013 by Federal Executive Agencies, SDG&E, and SCE. Reply comments were filed on April 9, 2013by SDG&E.

7. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Kelly A. Hymes is the assigned ALJ in this proceeding. Judge Hymes is the Presiding Officer.

Findings of Fact

1. Demand Response program data from the summer of 2012 indicates that SCE's Demand Response program events and event hours during this time are far less than the allowable maximum events and event hours.

2. Demand Response events overlapped price spike days, as defined for this review only, with varying degrees of success.

3. Decreasing the length and consecutive days of Demand Response events may decrease customer fatigue.

4. SDG&E's PTR program may not be a good fit for commercial customers.

5. The Demand Bidding Program revision requested by SDG&E improves the usefulness of the program by increasing the response time for addressing contingency situations identified by the CAISO and simultaneously meets the guiding principle to provide more demand response within 30 minutes.

6. SDG&E's Demand Bidding Program load impact was 5.1 MW in August 2012, 5.4 MW in September, and 4.6 MW in October.

7. The level of MWs anticipated for SDG&E's Demand Bidding Program will provide a small but consistent and reliable load impact.

8. SDG&E's request to augment and continue the Demand Bidding Program meets the requirements of this proceeding in that it improves the usefulness of Demand Response, meets one of the guiding principles, and is based on a lesson learned from the 2012 season.

9. SDG&E's request to issue an RFP for new load control technologies meets two of the guiding principles in that it considers a new source of load, i.e. pool pumps, and it could bring to light a new technology that could improve the performance of existing Demand Response programs.

10. SDG&E's RFP proposal could improve the usefulness of one or more demand response programs by considering new load sources.

11. SDG&E's RFP proposal request is not based on any lesson learned during 2012.

12. SDG&E's RFP proposal request could result in several new load control program possibilities.

13. SDG&E's Community Partners Initiative proposal would improve the usefulness of Demand Response programs by educating customers on the existence of such programs.

14. By expanding the Community Partners Initiative into South Orange County, SDG&E's proposal meets the guiding principle to focus on the SONGS affected area.

15. Results from the 2012 Flex Alert Campaign indicate that utilizing community-based organizations increased the number of customers benefiting from the knowledge provided.

16. Program results from 2012 indicate that SDG&E's Peak Time Rebate program for small commercial customers did not provide the load reduction anticipated.

17. Small commercial customers of SDG&E's PTR program used the opt-in alert at a lower rate than residential customers.

18. Small commercial customers have low awareness of SDG&E's PTR events.

19. Program results from 2012 indicate that SDG&E's PTR for small commercial customers is not successful.

20. Modifications to SCE's commercial Summer Discount Plan improve the availability of Demand Response programs, thus meeting one of the guiding principles of the Energy Division Letter.

21. Modifications to SCE's commercial Summer Discount Plan target the SONGS affected area, thus meeting a second guiding principle.

22. Modifying the SCE commercial Summer Discount Plan from an emergency to an economic-based program increases the ability to rely on this program.

23. 2012 Demand Response program data indicates that customers are motivated by maximum savings but prefer shorter curtailment events.

24. SCE's proposed revisions to its commercial Summer Discount Plan provide customers the options for maximum bill savings while increasing load impact.

25. SCE's proposal to increase the enrollment of its Residential Summer Discount Plan improves the usefulness of Demand Response by increasing potential load impact.

26. Pinpointing additional marketing of the Residential Summer Discount Plan meets the guiding principle of targeting the SONGS affected area.

27. Statistics from 2012 indicate that increased marketing to specific areas result in increased load impacts.

28. SCE's Auto Demand Response proposal targets customers in the SONGS affected area thus meeting one of the guiding principles of this proceeding.

29. SCE provides no data from 2012 Demand Response program results to show the impact of Auto Demand Response and why increasing the funding for incentives would increase the load impact.

30. Decision 12-04-045 states that limited data suggest that Auto Demand Response customers have a higher participation rate in Demand Response programs.

31. In Decision 12-04-045, PG&E testimony suggests that Auto Demand Response customers provide better load shed.

32. There is a high probability that SCE customers receiving Auto Demand Response incentives will provide 16 MW of additional load shed in 2013 and 2014.

33. Additional funding for targeted Flex Alert outreach should improve the usefulness of Demand Response by educating customers on conservation efforts.

34. Targeting marketing and outreach efforts for Flex Alert in the SONGS affected area meets a guiding principle for this proceeding.

35. Studies from 2012 indicate that targeted efforts are successful in educating customers and may lead to increased efforts to conserve energy during peak usage hours.

36. SCE's proposed Emerging Technologies Studies, if successful, will improve the usefulness of Demand Response programs by increasing load impacts.

37. SCE's proposed Emerging Technologies Studies focus on customers in the SONGS affected area and target new sources of load that can be reduced, thus meeting two guiding principles of this proceeding.

38. Customer surveys from 2012 indicate that less than five percent of respondents turn off pool pumps.

39. Sixty-five percent of Summer Discount Plan customers surveyed express a desire for shorter, more frequent Demand Response events.

40. Using Open Auto Demand Response could result in shorter event durations for customers.

41. SCE's proposed Emerging Technologies Studies rely on lessons learned from 2012.

42. SCE's three Save Power Day proposals target the SONGS impact area thus meeting a guiding principle for this proceeding.

43. Survey data from 2012 indicate that targeted education and marketing is successful.

44. Survey data from 2012 indicates that a day-of notification for the Save Power Day is not necessary.

45. Survey data from 2012 provides no indication of a need for an incentive increase for Save Power Day customers in the SONGS affected area.

46. Offering an increased incentive to all Save Power Day customers in the SONGS affected area could decrease the incentive for customers to install or adopt enabling technologies.

47. Increased incentives for Save Power Day could exacerbate the structural benefit issue.

48. Adding the three new Electric Vehicle rates to SDG&E's PTR tariff meets two guiding principles: increasing Demand Response in the SONGS affected area and providing a new source of load.

49. Adding the three new Electric Vehicle rates to SDG&E's PTR tariff is not a result of a lesson learned from 2012 Demand Response program data.

50. SDG&E's Electric Vehicle Pilot report indicates that customers are currently charging electric vehicles during off-peak times.

51. A change in the PTR tariff such as that suggested by SDG&E could have adverse effects on both the PTR program and the Electric Vehicle charging program.

52. Continuing the practice of SDG&E providing incentives to customers who use In Home Display units meets the guiding principle of targeting customers in the SONGS affected area.

53. Data from SDG&E's 2012 PTR program performance indicates that, during PTR events, customers with an in-home display unit saved more energy than customers without the in-home display unit.

54. SDG&E's request to fund shift $2 million from the Statewide Marketing, Education and Outreach proceeding to this proceeding does not meet any of the guiding principles of this proceeding nor is it based on any demand response program data from 2012.

55. SDG&E's request to fund shift $2 million from the Statewide Marketing, Education and Outreach proceeding to this proceeding violates the fund shifting rules.

56. SCE's revised Capacity Bidding Program meets the requirements of D.12-04-045 to make improvements to the program that result in a TRC cost-benefit ratio of at least 0.75 in 2013.

57. The Commission plans to open a new Demand Response rulemaking to consider revisions to the cost effectiveness protocols.

58. SDG&E's request to fund shift $4.98 million from the PTR Commercial program fund to the Capacity Bidding Program fund is consistent with current fund shifting rules.

59. SDG&E's request to shift funds from the 2012 Demand Bidding Program to the 2013-2014 Demand Bidding Program is consistent with current fund shifting rules.

60. Current fund shifting rules prohibit fund shifts between categories.

61. Nothing in the record of this proceeding leads us to change the fund shifting rules.

62. SCE requests to shift funds that were authorized outside of the 2012-2014 Demand Response Program and Budget proceeding.

63. Revisions requested in this proceeding are required to mitigate 2013 and 2014 potential reliability issues resulting from the outage of the SONGS units.

Conclusions of Law

1. It is reasonable to approve SDG&E's proposal to continue but revise its Demand Bidding Program.

2. It is reasonable to approve SDG&E's proposal to issue an RFP for new and innovative load control technologies.

3. It is reasonable to approve SDG&E's proposal to continue and expand the Community Partners Initiative into South Orange County.

4. It is reasonable to approve the elimination of SDG&E's small commercial customer option of its PTR.

5. It is reasonable to approve the modifications to SCE's Commercial Summer Discount Plan.

6. It is reasonable to approve the targeted marketing for SCE's Residential Summer Discount Plan.

7. It is reasonable to approve SCE's request to increase funding for its Auto Demand Response Incentives program.

8. It is reasonable to approve SCE's proposal to target Flex Alert education and outreach efforts to the SONGS affected area.

9. It is reasonable to approve SCE's three Emerging Technologies Studies.

10. It is reasonable to deny SCE's proposal to implement a day-of notification to Save Power Day customers.

11. It is reasonable to approve SCE's proposal to increase Save Power Day education and outreach efforts to customers in the SONGS affected area.

12. It is reasonable to deny SCE's proposal to implement a trial to increase incentives to Save Power Day customers in the SONGS affected area.

13. It is reasonable to approve the SDG&E requested tariff changes augmenting its Demand Bidding Program and eliminating its PTR commercial product.

14. It is reasonable to deny SDG&E's request to add three experimental Electric Vehicle rates to its PTR eligibility list.

15. It is reasonable to approve revision of SDG&E's PTR tariff to include In Home Display units as an enabling technology.

16. It is reasonable to deny the request of SDG&E to fund shift $2 million from the Statewide ME&O application to this application.

17. It is reasonable to approve the operation during 2013 of SCE's Capacity Bidding Program with a TRC cost benefit ratio of 0.75.

18. It is reasonable to approve SDG&E's request to shift $4.98 million from its PTR Commercial program fund to the Capacity Bidding Program fund.

19. It is reasonable to approve SDG&E's request for an additional $1.6 million for the 2013-2014 Capacity Bidding Program to recover costs shifted to the PTR Commercial program in 2012 and to fund the approved Community Partners Initiative.

20. It is reasonable to approve SDG&E's request to shift $1.76 million from the 2012 Demand Bidding Program to the 2013-2014 Demand Bidding Program.

21. It is reasonable to approve a $8.8 million shift of funds from the Summer Discount Plan Transition program to the 2012-2014 Demand Response Budget – Category 2.

22. It is reasonable to allow a one-time exemption to SCE to shift funds from the 2012-2014 Demand Response Budget – Category

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company's request to continue its Demand Bidding Program with the requested revision is approved.

2. A total budget of $1.76 million for years 2013 and 2014 is authorized to fund the San Diego Gas & Electric Company's Demand Bidding Program.

3. San Diego Gas & Electric Company's request to issue a Request for Proposal for new and innovative load control technologies is approved.

4. San Diego Gas & Electric Company (SDG&E) shall work with the Commission's Energy Division to develop a Request for Proposal (RFP) that provides ample opportunities to capture new and innovative load control technologies. SDG&E shall issue the RFP no later than 45 days following the issuance of this decision in order to implement new programs in time for the summer of 2014.

5. San Diego Gas & Electric Company's request to continue and expand its Community Partners Initiative is approved.

6. A total budget of $200,000 for years 2013 and 2014 is authorized to fund the expansion of San Diego Gas & Electric Company's Community Partners Initiative.

7. San Diego Gas & Electric Company shall eliminate the small commercial option of its Peak Time Rebate program.

8. Southern California Edison Company's request to modify the Commercial option of its Summer Discount Plan is approved.

9. A total budget of $693,000 for years 2013 and 2014 is authorized to fund the transition of the economic dispatch for the Commercial option of Southern California Edison Company's Summer Discount Plan.

10. Southern California Edison Company's request to target marketing of the Residential option of its Summer Discount Plan is approved.

11. A total budget of $1.9 million for years 2013 and 2014 is authorized to fund the increased marketing for the Residential and Commercial options of Southern California Edison Company's Summer Discount Plan.

12. Southern California Edison Company's request to increase the number of incentives provided to customers through the Auto Demand Response incentive program is approved.

13. Southern California Edison Company's requested additional budget of $5 million for its Auto Demand Response incentive program is authorized.

14. Southern California Edison Company shall allocate $4.2 million of its Auto Demand Response incentive program budget solely for customer incentives.

15. Southern California Edison Company shall ensure that its Auto Demand Response program adheres to the Auto Demand Response program requirements from Decision 12-04-045.

16. Southern California Edison Company's request to target Flex Alert marketing and outreach to the San Onofre Nuclear Generating Station affected area is approved.

17. An additional total budget of $175,000 for years 2013 and 2014 is authorized to fund the Southern California Edison Company's Flex Alert targeted marketing and outreach.

18. Southern California Edison Company's request to perform three Emerging Technologies Studies is approved: a two-year pool pump education measure study, a 2013 Home Area Network controlled pool pump study, and a two-year third-party Programmable Controllable Thermostat study.

19. A total two year budget of $975,000 is authorized to fund the Southern California Edison Company's Emerging Technologies Studies as follows: $500,000 is authorized to fund the two-year pool pump education measure; $350,000 is authorized to fund the 2013 Home Area Network controlled pool pump study; and $125,000 for 2013 and 2014 is authorized to fund the two-year Programmable Controllable Thermostat study.

20. Southern California Edison Company's Emerging Technology projects approved in this decision shall comply with the Emerging Technology project reporting requirements as discussed in Decision 12-04-045.

21. Southern California Edison Company's request to increase Save Power Day education and outreach efforts to customers in the area affected by the San Onofre Nuclear Generating Station is approved.

22. San Diego Gas & Electric Company shall revise its associated tariffs to conform to the approved changes in the Demand Bidding Program and Peak Time Rebate program.

23. San Diego Gas & Electric Company shall submit, via a Tier One Advice Letter no later than 14 days from the issuance of this decision, its revised Demand Bidding Program and Peak Time Rebate program tariffs.

24. Southern California Edison Company's request to operate its Capacity Bidding Program in 2013 is approved.

25. Southern California Edison Company shall submit Capacity Bidding Program revised cost benefit ratios for 2014 following any changes to the cost-effectiveness protocols resulting from a Commission review. Southern California Edison Company shall submit its revised Capacity Bidding Program revised cost benefit ratios via a Tier Two Advice Letter no later than 30 days following the issuance of a decision on the Demand Response program cost effectiveness protocols.

26. San Diego Gas and Electric Company and Southern California Edison Company shall submit, via a Tier One Advice Letter within 14 days of the issuance of this decision, all required tariff changes associated with the approved changes in this decision.

27. San Diego Gas & Electric Company is authorized to shift $4.98 million from its Peak Time Rebate Commercial program fund to its Capacity Bidding program fund for 2013-2014.

28. San Diego Gas & Electric Company is authorized an additional $1.43 million for its 2013-2014 Capacity Bidding Program to recover costs shifted to the Peak Time Rebate Commercial program in 2012 and $200,000 to fund the 2013-2014 Community Partners Initiative as approved herein.

29. San Diego Gas & Electric Company is authorized to shift $1.76 million from its 2012 Demand Bidding Program fund to its 2013-2014 Demand Bidding Program.

30. Southern California Edison Company is permitted a one-time exemption from the fund shifting rules and is authorized to shift $8.8 million from the Summer Discount Plan Transition program to the 2012-2014 Demand Response Budget – Category 2 and then shift $5.975 million to Category 4 and $2.106 million to Category 7.

31. Commission staff shall continue to study the 2012 Demand Response Program data from San Diego Gas & Electric Company and Southern California Edison Company and develop a report describing lessons learned from this data. Staff is encouraged to make further recommendations for program revisions that improve the Demand Response programs based on 2012 data. Commission staff shall submit and serve the report no later than April 30, 2013. Parties to this proceeding and other interested stakeholders may file and serve comments to this report no later than 14 days after the filing of the Commission Report.

32. Application 12-12-016 et al. shall remain open to address the Commission Report.

This order is effective today.

Dated _____________________________, at San Francisco, California.

APPENDIX A

STATE OF CALIFORNIA Edmund G. Brown Jr., Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 16, 2012

Mr. Akbar Jazayeri
Vice President of Regulatory Operations
Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, CA 91770

Mr. Clay Faber, Director
Regulatory Affairs
San Diego Gas and Electric Company
8330 Century Park Court
San Diego, CA 92123

Subject: Energy Division Request for Demand Response Program Applications for Summer 2013 and 2014

Dear Messrs. Jazayeri and Faber:

On January 9, 2012, San Onofre Nuclear Generating Station (SONGS) Unit 2 was taken out of service for a planned outage and on January 31, 2012, Unit 3 was taken off line after station operators detected a leak in one of the unit's steam generator tubes. SONGS provides substantial capacity to the Southern California region and it is my understanding that these units might not be brought back into service before the summer of 2013 or 2014.

The unavailability of the SONGS units for future summers is a concern, particularly in the event of an unexpected generation outage, loss of transmission, or a stretch of hot weather that would strain the state's electrical system in Southern California.

In an effort to protect the state's electrical system from compromises to its reliability, I am initiating further Commission consideration of utility demand response (DR) programs in the SCE and SDG&E service territories for the summers of 2013 and 2014. Accordingly, SCE and SDG&E should submit Applications proposing program improvements and augmentations to their existing demand response (DR) program portfolios[71].

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1. On April 19, 2012, the Commission issued a decision which adopted 2012 – 2014 budgets for Demand Response (DR) programs of Southern California Edison Company

Footnote continued on next page

Messrs. Jazayeri and Faber
November 16, 2012
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I am not asking SCE and SDG&E to re-submit their entire DR portfolios but to identify a handful of specific program changes or additions that would improve the usefulness or availability of DR in 2013 and 2014. SCE and SDG&E should use the following guiding principles to focus their efforts:

- Geographic areas affected by the unavailability of SONGS (south Orange County and South of Lugo for SCE and the greater San Diego region). New programs or variations to existing programs that increase DR capability in these locations.

- Consideration of new sources of load that can be reduced (pool pumps for example) or incenting participation by customer segments who have been under-utilized.

- Programs that can provide demand response within 30 minutes are preferable as quick response capability is the most useful for addressing contingency situations identified by the CAISO for summer 2012 planning.

- Changes to any existing DR program that improve its performance such as making its load reduction capacity more dependable, consistent and predictable.

- Modifications to triggering conditions that increase the availability and/or flexibility of programs should also be considered.

- Consideration of all aspects of DR programs, not limited to program design features but may include operation, coordination, and communication practices of utility staff.

SCE and SDG&E should rely on 'lessons learned' about DR events from the summer of 2012 (e.g. load impact, evaluations of DR programs, customer response) and submit such information in the Applications. The attachment to this letter contains specific data requests and questions that Energy Division expects SCE and SDG&E to respond to in their respective Applications.

(SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E). These programs were adopted to promote shifts in electricity consumption in response to either price signals or financial incentives, primarily during times when reliability is compromised or the electricity system is vulnerable to extremely high prices.

To the extent that the SCE and SDG&E request new funding[72] for their proposals, they should provide a cost-effectiveness analysis of their proposal(s) in compliance with the existing DR cost-effectiveness protocol[73] and cost-effectiveness policies as adopted in D.12-04-045. To the extent that SCE and SDG&E will rely on fund-shifting from existing DR funds, such shifts should be thoroughly described (e.g. programs from where the funds would be transferred). If changes to existing fund shifting rules are proposed, such changes should also be described and justified.

Messrs. Jazayeri and Faber
November 16, 2012
Page 3

I request SCE and SDG&E to file their Applications no later than December 21, 2012, so that the Commission has enough time to process the information and render a decision prior to the summer of 2013. The utilities may provide updates and/or supplemental proposal(s) on January 31, 2013 to reflect the most recent Ex Post load impact data.

If you have any questions regarding this request, please contact Bruce Kaneshiro at (415) 703-1187.

Sincerely,

Edward Randolph
Director, Energy Division
California Public Utilities Commission

Attachment: Energy Division Guidance for
Post Summer 2012 DR Evaluation & 2013/2014 Summer Planning

cc: A.11-03-001 et al.

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2. New funding is defined as funding that is incremental to existing funds for the utilities' 2012-14 DR portfolios authorized in D.12-040-045 and other proceedings.

3. Adopted in D.10-12-024.

Attachment

Energy Division Guidance

for Post Summer 2012 DR Evaluation and 2013/2014 Summer Planning

1. <u>Demand Response Program performance</u>

   a) Load impact (MWs) and participation

   - **Data:** provide the load impact, enrollment and number of participants information for each of DR programs categorized by: 1) Monthly Nominated Programs, 2) Other Price-Responsive, and 3) Emergency[74] Programs; and by program types (Day Ahead/Day of). The DR program listed under each of these categories should be consistent with the programs referred to in the IOUs DR Weekly Forecasts/Daily Reports that have been submitted to the CPUC and CAISO in summer 2012.
     - Provide the load impact, enrollment, and number of participants for each DR event and a summary table for each of the five summer months (June, 2012 to October, 2012). The monthly value should be determined by the highest load impact (MWs) of the DR events in a given month (similar to the RA monthly load impact). Provide the temperature and system peak load in the utility's service territory for each event day.
     - If separate subgroups of the enrolled customers within a program were dispatched in different DR event hours, the load impact for that event day should be the aggregate of all of the customers triggered. For example, SCE may have dispatched three different groups of residential AC cycling customers in three different event hours; the load impact for the residential AC cycling customers should be the sum of the load impact from each group of customers.
     - The number of participants is defined as the number of customers or accounts that were used to determine the load impact in the seven day results reports submitted to the CPUC and CAISO in 2012. The number of participants may be fewer than the total number of customers enrolled under each program. For example, for SCE's residential default Peak Time Rebate (PTR) program, the total enrollment for this program is the total residential population that is eligible to receive a rebate, but SCE may use the number of customers who signed up for the notification as the number of participants.
     - For SCE, provide the Ex Post load impact and number of participants for the South of Orange County and South of Lugo. These two areas should be defined consistent with the same areas identified by the CAISO in the Daily DR Report.

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[4]. As categorized in the DR Daily Reports and the Weekly Forecasts. Some programs are referred to as Reliability Programs such as the Base Interruptible Program (BIP) and others are referred to as price-responsive programs such as AC cycling.

- **Data source**: use the hourly load impact data that were relied upon for the seven-day result reports submitted to the CPUC and CAISO in 2012. Provide a brief summary of the methodologies that describe how the hourly load impact (MWs) were developed.
    - The utility should also provide an update of the load impact and number of participants based on the settlement billing data for each DR event and a summary of the monthly load impact.
    - The utilities may provide an update when the Ex Post load impact data based on the Load Impact Protocols becomes available (no later than January 31, 2013). Provide a brief summary of the methodologies describing how the Ex Post hourly load impact (MWs) were developed.
    - By February 2013, for each DR program provide a historical monthly load impact comparison (for the summer months only) between the seven day results reports provided to the CPUC and CAISO, settlement billing data, and the Ex Post data for 2010 to 2012.
- **Averaging period**: for programs that have different hourly load impact, produce two sets of data to determine the daily value for each DR event: 1) the event hours and 2) the RA measurement hours (1 p.m.-6 p.m.)
- **Comparison analysis:**

    Q.1: How does the DR program load impacts compare with the 2012 DR allocation for RA for each of the summer months (June, 2012 to October, 2012)? Please provide a table that includes all programs.

    Q.2: How does the DR program load impact compare with the 2012 DR allocation for RA taking into account up-to-date information such as enrollment and weather changes? In other words, did the DR programs perform as expected when the programs were triggered? Please provide a comparison table that includes all programs.

    Q. 3: Did the utility observe any evidence of customer fatigue as a result of consecutive DR events on multiple days? If the answer is yes, how much did the customer fatigue affect the load impact?

b) DR operation

- **DR program information:** provide a summary of all DR program availability (maximum hours/events per month/year), triggering criteria, by the same categories as in 1.a).

    Provide a summary of the DR programs events including total number of hours and events triggered and the list of triggering conditions in comparison with the program maximum hours and events.. For example, if a DR program is has a maximum of 180 hours and it was triggered a total of 22 hours, the comparison should show both 22 triggered and 180 maximum hours.
- **Comparison analysis:**

Q.1: How often was each of the DR programs triggered as compared to the corresponding program availability? Provide a comparison between the program's operating limit and its actual events and hours per month/year.

Q. 2: What were the reasons for any of the DR programs operated under the operating limit, e.g., triggering conditions, customers' annoyance, system load and resource conditions, etc.

Q. 3: Provide a comparison of the DR program summer historical operational data for each DR program organized by the three categories listed in I.1.a) from 2006 to 2012: actual number of DR events vs. maximum events, actual total event hours/month or summer vs. maximum event hours/month or summer.

Q. 4: Provide a comparison of the historical operational data for the utility's peaker plants, e.g, combustion turbines from 2006 to 2012: actual dispatched hours vs. maximum hours allowed by permit.

2. <u>CAISO Markets</u>

a) Price spikes

- Provide a mapping of the day-ahead or real time wholesale energy price spikes and the DR events for each of the summer months (June, 2012 to October, 2012).

b) Market analysis

Q.1: Were price-responsive DR programs used to avoid paying for and mitigate these price spikes? If not, why not?

Q.2: If the answer to Q.1 is yes, did the utility observe any change in market prices or impact on supply constraints or congestion experienced in the market?

Q.3: If the answer is to Q.1 is no, are there any current DR programs that could be modified to address the price spikes (day-ahead or real time)? What are the specific modifications and does it make sense to make those changes?

Q.4: For DR programs that have a price trigger, was the trigger set too high or too low? Was it reasonable?

3. <u>Customers' Experience</u>

- **Alignment between DR program operation & design and customers' expectations:**

Q. 1: What was the utility's overall customer experience with the DR programs in summer 2012?

Q.2: What feedback (complains or problems) did the utility receive from customers about the DR events?

Q.3: Based on the feedback received by the utility, did any of the customers (and the percentage) feel that there were too many DR events last summer?

Q.4: Did any of the customers (and the percentage) feel that the incentives they received were too low or unfair?

Q.5: Are there any lessons learned from the customer perspective particularly for AC cycling, Peak Time Rebate, Demand Bidding Program, Capacity Bidding Program, Critical Peak Pricing, 10-in-10 program?

- **Customer awareness and participation:** provide an analysis of the Peak Time Rebate program on customer participation and free ridership.

  Q. 1: Which group(s) of customers (those who signed up for notification, those who received notification through My Account, those without direct notification) provided the most load reduction under each DR program and what was the reason(s)?

  Q.2: Were the DR event notification systems effective?

- **Program Evaluation**: it is our understanding that SCE is doing a program evaluation of its 10-in-10 program and SDG&E is doing an evaluation of its Peak Time Rebate program. To the extent that these evaluations are available by January 2013, the utilities should submit these reports to the CPUC for consideration.

4. Coordination with CAISO and Utility Operations

- Daily and Weekly DR Reporting

  Q.1: From the IOUs' perspective, was the daily and weekly DR reporting helpful to the utility? What could be improved?

  Q.2: Please describe communication and coordination efforts between utility DR program staff and utility procurement staff and grid operation staff on day-to-day usage of demand response programs.

- DR coordination/communication

  Q.3: What are the utility's internal operational procedures for the DR programs (price responsive and emergency)? Provide examples of how the utility triggered and communicated DR events with its energy center and grid operator for August 8, 9, 10, & 14, 2012, September 14, 2012, and October 2, 2012.

  Q.4: Were the DR forecast communicated to the utility's energy center and grid operation consistent with what had been reported to the CAISO in the Daily DR Reports? If not, why?

  Q.5: Are there other coordination/communication issues between the IOUs and CAISO that the Commission should address by summer 2013?

5. Emergency DR Dispatch Order

   1. **Dispatch order:** Under the CAISO's current emergency operational procedure (No.4420, Section 3.3.2) and pursuant to the Settlement Agreement adopted in D.10-06-034), the utilities' Base Interruptible Program (BIP) and SCE's API program and commercial AC

cycling program cannot be dispatched until after the CAISO dispatches non-RA resources and canvases other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties.

Q.1: If CAISO's dispatch order was revised such that non-RA resources and other entities /balancing authorities are dispatched AFTER BIP, AP-I, and commercial AC cycling programs are dispatched, would that revision have resulted in additional BIP, AP-I and commercial AC cycling events in 2012? If so, how many events, and on what days?

Q.2: Should this dispatch order be moved up in the operational procedure so the CAISO can dispatch the emergency DR before dispatching non-RA resource and canvasing resources from outside of its system? If the answer is no, explain why emergency DR (which is an RA resource) should be dispatched after the CAISO dispatches non-RA resources.

Q.3: If the answer is yes, how can the dispatch ordered be changed? What is the best process to address this issue?

6. Flex Alert (If the utility needs additional time for the analysis, it can be provided in the January 31, 2013 updates or supplemental testimony).

- **Effectiveness:** provide a mapping of the CAISO's Flex Alert(s) and the utility's DR events. For the Flex Alert(s) that coincided with the utility's DR event(s), provide the utility's best estimate of the load impact that can be attributed to the Flex Alert(s).

  If there was no DR event during a Flex Alert, provide the utility's best estimate of the load reduction that it observed, that can be attributed to the Flex Alert(s)

  Provide the methodology (ies) for the estimates, e.g., methods similar to the Ex Post load impact analysis.

  Q 1: What was the utility's experience with the Flex Alert? Was there any communication between the CAISO and the utility prior to the issuance of the Flex Alert and coordination for the DR events?

  Q.2: What was the customers overall experience with Flex Alert? Were there any customer confusions between the Flex Alert and the utility DR event notifications?

  Q.3: Should the Flex Alert be continued for 2013 and 2014? If so, are there ways to improve the effectiveness of the Flex Alert program?

(END OF APPENDIX A)